The need for a FAM substitute

A report to EirGrid, SONI and the Regulatory Authorities

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1 Introduction

The SEM Committee (SEMC) has directed the TSOs (EirGrid and SONI) to introduce a Day-Ahead System Service Auction (DASSA) to replace the current System Services procurement arrangements. In the first instance, the DASSA will be used for reserve products, with the target date for the auction go-live set for December 2026.

In March 2024, the TSOs consulted on the DASSA design with the industry and subsequently submitted a recommendations paper to the SEMC in July 2024. The SEM Committee, in September 2024, published the DASSA Market Design decision paper[1]. Most of the TSOs' recommendations were approved by the SEM Committee in its decision, however, with two notable exceptions:

- the Final Assignment Mechanism (FAM), which was designed to incentivise service providers to make themselves available in real time, was not approved;
  - design of an alternative procurement framework to renumerate service providers for their real-time availability is part of a separate work stream, which is yet to be consulted upon and will be subject to SEMC decision; and
- the SEMC reserved its decision on the application of a Compensation Payment, which is payable to the TSOs in the event of a lapsed DASSA Order, and directed the TSOs to conduct a consultation on the valuation and application of Compensation Payments.

The FASS HLD included a decision to include a top-up auction with the intention to ensure sufficient volumes were procured should all winners of the market auctions not be capable of providing the services. The SEMC also suggested that the total volumes 'cleared' should not exceed the forecast volume requirement.

The issues the SEMC sees with the FAM are the following:

- there is no understanding of the FAM requirements and units cannot account for this in their bidding in the intraday energy markets – it would simply act as a compensation mechanism;

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[1] https://www.semcommittee.com/files/semcommittee/2024-09/SEM-24-066%20-%20SEMC%20FASS%20DASSA%20Design%20Decision%20Paper.pdf

- inability to update bids closer to real-time means bids are outdated and the FAM clearing price will not reflect the true value of closer to real-time provision;
- the introduction of a fully automated secondary market and the removal of compensation payment protections mitigates the need for a top-up auction; and
- zero volumes bids and volume capped bidding encourage reduced liquidity in both the DASSA and the secondary market;

The SEMC then also highlighted that this top-up mechanism should be ‘ramped down’ once a secondary market was in place. The presence of a secondary market from day 1 means there is less of a need for a top-up mechanism.

Consequently, the TSOs have commenced work on the “DASSA Real Time Security Need analysis” work package in the revised PIR V2.0[2] to address elements of the DASSA design that have not yet been finalised, or on which the SEMC decided to reserve judgement (as per above).

The scope of work envisaged “running an unconstrained Day Ahead Market (DASSA) and then running a constrained real time model”. The constraints should include “thermal and system-wide limitations, which are regularly published on the SEMO website”. Changes that take place between the Day-Ahead stage and real-time, such as changes in demand and renewables forecasts, and unit outages should also be considered in the analysis.

From then on, there are two sensitivities that should be assessed:

- one where the Balancing Market acts as a substitute to an explicit market/mechanism for procuring/renumerating reserve closer to real-time by “including reserve volumes, which may be available as a result of (i) being incentivised to remain available in the Balancing Market, and (ii) being repositioned in the Balancing Market to address non-energy actions”; and
- one, which recognises that in the absence of explicit incentives to provide reserves, units may end up offering the minimum volumes (under the Grid Code).

1.1 Structure of this report

This report is structured as follows:

- Chapter 2 presents the modelling methodology.
- Chapter 3 describes the impacts of constraints and analyses the difference in reserve supply at the DASSA stage and real-time.
- Chapter 4 discusses the conclusions of our analysis.

[2] FASS-TSOs-PIR-September-2024-EirGrid.pdf

2 Modelling approach

2.1 Modelling approach

With this analysis, we wish to assess the potential change in reserve volumes after the DASSA. We have assumed that the requirement for each reserve product remains unchanged between the DASSA and real-time (and equal to 1050MW), and we are only exploring the need for alternative volume as some volumes procured through the DASSA become unavailable. There are multiple reasons for DASSA volumes becoming unavailable:

- the TSOs take dispatch actions ahead of real-time to manage the All-Island system securely – there is a range of operational constraints, both system-wide (SNSP limit, inertia floor, minimum number of units for system-wide stability and RoCoF limitation), and more 'locational' ones (minimum number of units in specific locations or to manage congestion on specific lines);
  - this then means that some units will be synchronised or will increase their output and some units will be desynchronised or will decrease their output as the TSOs attempt to 'tweak' the market schedule to a technically feasible schedule;
- DASSA Order volumes becoming unavailable because of unit outages;
- units with a DASSA Order choosing to change their energy position in response to actual intraday electricity price movements with a knock-on impact on DASSA Order volumes;
  - this is effectively a commercial decision by market participants and the extent to which this happens will depend on the commitment obligation and the level of the applicable compensation payment;

We want to understand the changes in reserve provision as a result of all the above drivers. We, therefore, model:

- an 'unconstrained' Day-Ahead and DASSA;
  - the SEM is a single price area with no internal constraints and operational restrictions in terms of minimum number of thermal units online, SNSP limitations, inertia floor and RoCoF limitations. Our BID3 model is then attempting to find the least cost solution for meeting energy and reserve (FFR-RR) demand. This is equivalent to the results expected from the DAM and the DASSA. Both these markets are 'unconstrained' – all providers offer their capacity in these markets ignoring any actual constraints in physical dispatch;

- a constrained dispatch run;
  - we then include the applicable in each modelled year set of constraints (SNSP limit, inertia floor, minimum number of units constraints, the N-S tieline restriction and most other system-wide constraints);
- a constrained real-time dispatch run;
  - as part of this model run, in addition to the system-wide operational constraints described above, we also capture demand and RES forecasts errors and plant outages.

The constrained real-time dispatch run may not necessarily capture all redispatch as some will be a result of congestion on specific lines that are not necessarily part of the wider operational constraints published by EirGrid and SONI. The constrained real-time dispatch is modelled under three different 'cases':

- assuming a 'hard' constraint for all reserve volumes procured under the DASSA and all alternative volumes (all volumes that become unavailable due to non-energy actions and because of forced outages within-day are assumed to have been traded in the secondary market) – this then means the only possibility for unavailability are outages post Gate Closure;
- assuming the presence of the reserve constraints at the real-time stage and the implicit presence of a compensation payment equal to the delta between the real-time reserve price and the DASSA price; and
- assuming no reserve constraint in real-time and the implicit absence of any compensation payment.

We do not explicitly model the intraday and secondary reserve markets. We have been requested, however, to assume that secondary trading is effective and there are sufficient incentives for providers to trade up to Gate Closure. We have assumed this in the modelling of all cases that include a compensation payment (as there is limited incentive to trade in the secondary market in the absence of a compensation payment (unless more cost-effective reserve provision becomes available within-day)).

2.2 Modelling assumptions

2.2.1 Operational constraints

As already discussed, we are effectively modelling both an unconstrained market schedule and a constrained dispatch. The operational constraints included in the constrained dispatch model runs are detailed in Exhibit 1. We have included the majority of the existing operational constraints in modelled year 2027. However, in 2030 we assume that most of the constraints have been lifted. There is still an inertia floor, but the LCIS tenders are assumed to have delivered sufficient low carbon inertia provision with limited additional needs from thermal generating units. From then on there are no Minimum Number of Units constraints, and the only operational constraint is the N-S tieline.

Exhibit 1 – Operational constraints

Name	Description	2027	2030
SNSP	Limit on instantaneous non-synchronous generation	80%	99.9%
Inertia	Minimum inertia floor. Less binding with the introduction of synchronous condensers	23,000	25,000
Inter-Area flow	N-S tieline flow restrictions	400 (IE->NI) 450 (NI->IE)	400 (IE->NI) 450 (NI->IE)
RoCoF		Not modelled. This would not be a binding constraint given inertia constraint.	
System Stability	At least 7 units on-load	Not explicitly modelled – captured under the MUON EirGrid and SONI constraints we mode that ensure 7 thermal units are operational across the All-Island system.	
MUON EirGrid	This is the EirGrid System Stability constraint	4	0
MUON SONI	This covers the two System Stability constraints for Northern Ireland	3	0
Replacement Reserve SONI	GT and AGUs combined output less than 272MW	Yes	No
North-West Generation	Coolkeeragh online under specific conditions	Yes	No
Dublin Generation	At least one of the Huntstown and Dublin Bay units needs to be online at all times	Yes	No
Dublin Generation	At least two of the Huntstown, Poolbeg and Dublin Bay units need to be online at all times	Yes	No
Dublin Generation	At least two of the Huntstown, Poolbeg and Dublin Bay units need to be online when demand is greater than 4000MW	Yes	No
Dublin Generation	At least three of the Huntstown, Poolbeg and Dublin Bay units need to be online when demand is greater than 4700MW	Yes	No
400kV Netowrk	One of the Moneypoint or Tynagh units online to support the 400kV network	Yes	No

In 2030, the gap between the ‘unconstrained’ market schedule and the operational dispatch is very small. We do understand that this may not be possible by 2030. However, we wanted to have results also for the more ‘target’ system conditions, even if this may not be possible by 2030. Exhibit

1 describes the operational constraints we have included in the constrained model runs. These are based on the current operational constraints. We have assumed those persist in 2027, but most of these are removed or relaxed in 2030.

The above operational constraints ignore the minimum level of regulating reserve that is needed in each jurisdiction. The inclusion of this additional constraint could further broaden the gap between the 'unconstrained' market schedule and dispatch, but this will also depend on whether there is a minimum requirement of regulating reserve procured in the DASSA or not.

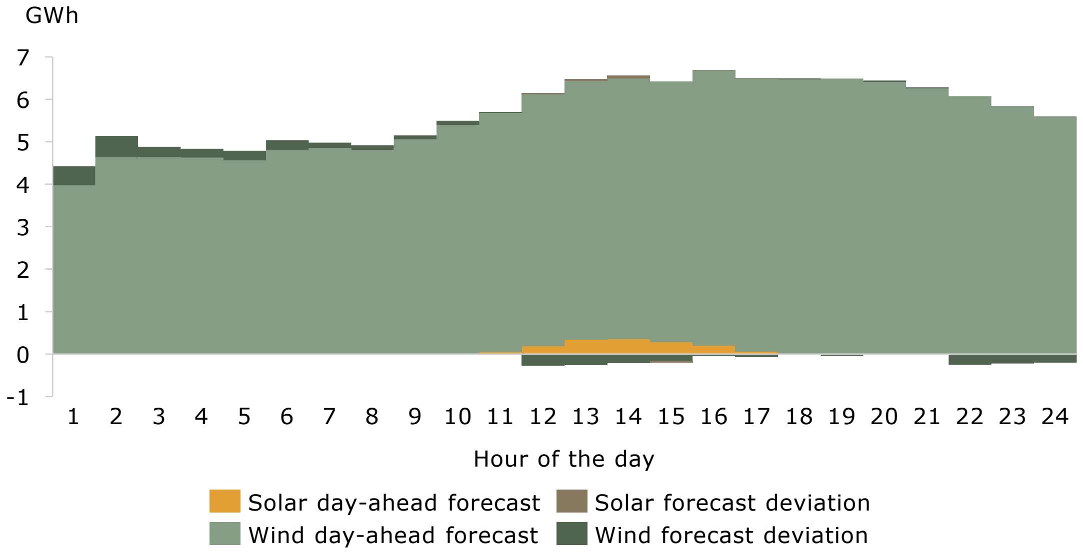
2.2.2 Other assumptions

Some of the key assumption of the scenario modelled, including demand, installed capacity mix and commodity price assumptions, are presented in Annex A.

For the real-time model runs we are using our standard assumptions for the change in demand and renewables output to account for deviations against the day-ahead forecast (forecast errors). These are based on historical statistical analysis. In the below chart we show the wind and solar forecast and the respective deviations in real-time for an indicative day.

Exhibit 2 – Deviation from the forecast example

The initial forecast for generation of solar and wind will be set at the day-ahead stage; the real-time stage will apply a function to determine the deviation over said forecast, which can be either positive or negative, as shown in the chart. For demand, the behaviour is equivalent.



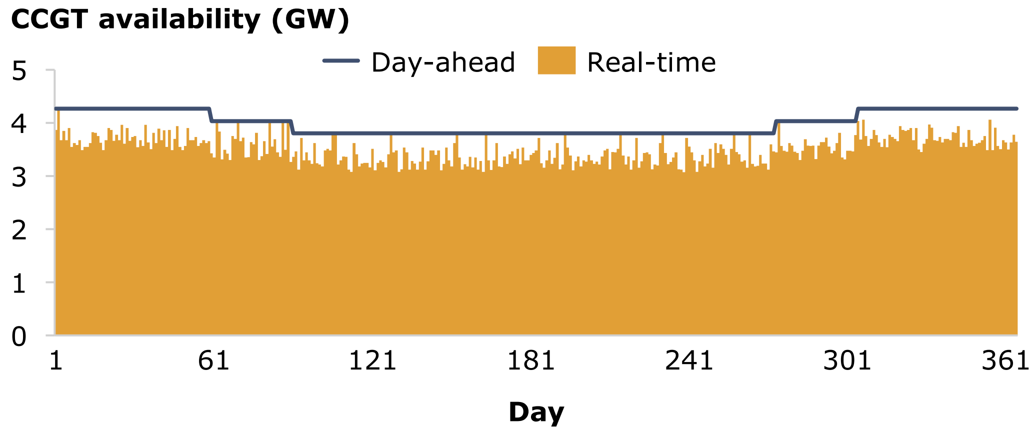
We also include plant outages. In line with the "All-Island Transmission System Performance Report 2023" [3], we assume a 12% forced outage

[3] https://cms.eirgrid.ie/sites/default/files/publications/All-Island-Transmission-System-Performance-Report-2023.pdf

probability for CCGTs. The resulting modelled availability for the entire CCGT fleet can be seen on Exhibit 3. This ignores plant maintenance.

Exhibit 3 – Availability assumptions for CCGTs (GW)

Real-time availability considers that CCGTs trip 12% of the hours



Notes: Based on EirGrid and SONI data for the year 2023

2.3 Modelled cases

The below table summarises the modelled cases. We model effectively three 'stages':

— the Day-Ahead time frame (DAM and DASSA);

— the market schedule produced from the above acts as the starting point for subsequent dispatch instructions that take place ahead of real-time (constrained dispatch);

— finally, we model the real-time, which uses the constrained dispatch as the starting point, but includes updated inputs with respect to plant availability.

Exhibit 2 maps the various model runs performed and how these are then used to extract results and assess the different the outcomes.

We have not modelled the 'High compensation payment' case with BID3. This would have been redundant as we would have had to include a 'hard' constraint that would not allow any ex-ante reserve volumes to be 'released' in real-time. We have instead statistically determined the average expected technically available provision. In the presence of a high compensation payment all DASSA volumes that can no longer deliver volumes have a very strong incentive to sell in the secondary market to avoid facing the compensation payment.

Exhibit 4 – Summary of modelled cases

Model run	Description	Modelled case
Unconstrained market schedule	This BID3 model run attempts to minimise the short-run cost of meeting electricity demand and the upward reserve constraints (FFR-RR). It co-optimises energy and reserve. It is a proxy for the 'unconstrained' DAM the DASSA. Includes Day-Ahead expectations for RES and demand.	'Unconstrained' DAM and DASSA
Constrained dispatch	This BID3 model run attempts to minimise the short-run cost of meeting electricity demand and the various reserve requirements, whilst also respecting all operational constraints (N-S tieline, SNSP, MUON etc.). This run should resemble the results of the LTS (or an equivalent scheduling and dispatch process). It does not include all congestion that may arise on the system. RES and demand assumptions are the same as those in the Unconstrained DAM & DASSA run.	Constrained dispatch
Constrained real-time dispatch	This BID3 run is the same as the Constrained dispatch with updated RES output and demand, and the inclusion of plant outages. This is meant to reflect changes that happen as we approach closer to real-time.	Real-time dispatch position assuming 'Mid compensation payment'
Constrained real-time dispatch (no reserve)	This BID3 runs is the same as the Constrained real-time dispatch run, but without the inclusion of the reserve constraints.	Real-time dispatch position assuming 'No compensation payment'
Constrained real-time dispatch (no change in reserve)	This model run uses the Constrained dispatch as a basis and has different RES output and demand, and the inclusion of random plant outages, reflecting changes that happen as we approach closer to real-time. However, it also assumes that the reserve provided by the different units cannot be changed.	Real-time dispatch position assuming 'High compensation payment'

3 Changes between DASSA and real-time

3.1 How does the ‘unconstrained’ market compare to the constrained dispatch?

It is important to understand how the BID3 model works. The model schedules all resources on the system attempting to find the least cost solution, given a set of technoeconomic inputs for the different generation assets, to meet energy and reserve demand, whilst satisfying all other constraints included in the optimisation.

When it comes to reserve, it will schedule units to have sufficient headroom (and/or footroom assuming also modelling of downward reserve) to meet the reserve requirements[4]. The reported reserve volumes will be those that deliver the overall least cost solution – not just from the perspective of the reserve market, but from the overall system cost perspective. All other system-wide and ‘locational’ constraints can have a significant impact on the results of the constrained model run.

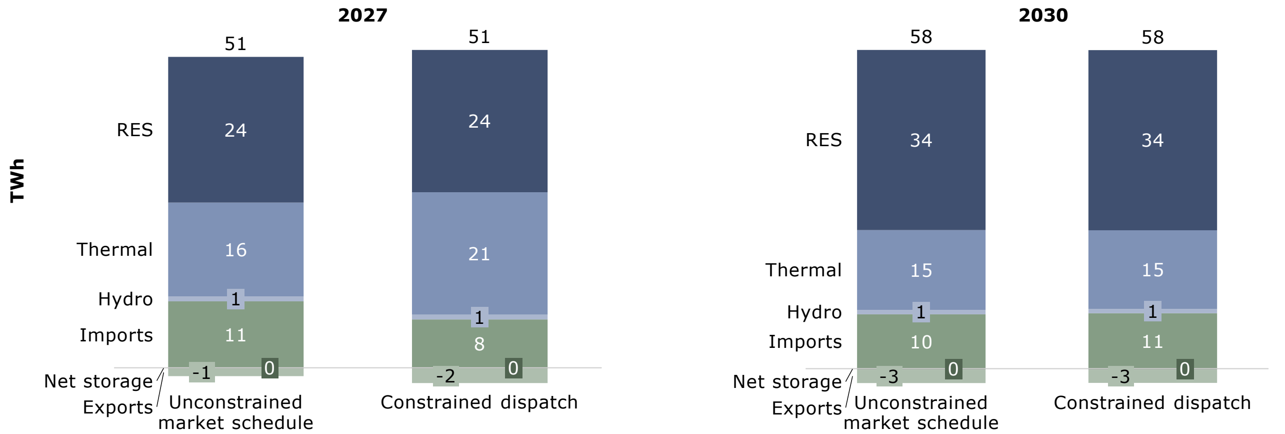
A minimum number of thermal units will need to be synchronised at all times, even when there is no need for their output to meet energy demand, and even if the variable cost of such generation is greater than alternative generation. Such units will be scheduled at minimum load (or below their max output) and will have available headroom, which can be used to meet the reserve requirements. This reserve provision is effectively ‘free’ given that the minimum number of units constraints is a ‘hard’ constraint.

Exhibit 5 shows the resulting generation for the ‘unconstrained’ market schedule (that ignores system-wide constraints, but includes the reserve requirements) and a constrained dispatch in 2027 and 2030 respectively. In 2027, this results in a significant change in the generation mix. Some of the renewable non-synchronous generation (around 0.5TWh) has to be ‘turned down’, imports have to be restricted (by around 3TWh) and replaced by additional thermal generation (around 5TWh). At the same time, storage cycles more in an attempt to avoid further renewable dispatch down. This also highlights the role storage can have for reducing RES turned down volumes.

[4] For simplicity we have modelled only upward reserve in this analysis

In 2030, there is very little difference between the 'unconstrained' market schedule and the constrained dispatch. This is because we have assumed that the majority of the system-wide constraints have disappeared in 2030 (even if this is very unlikely to happen within this short timeframe).

Exhibit 5 – Annual generation (TWh) in 'unconstrained' market schedule and real-time dispatch



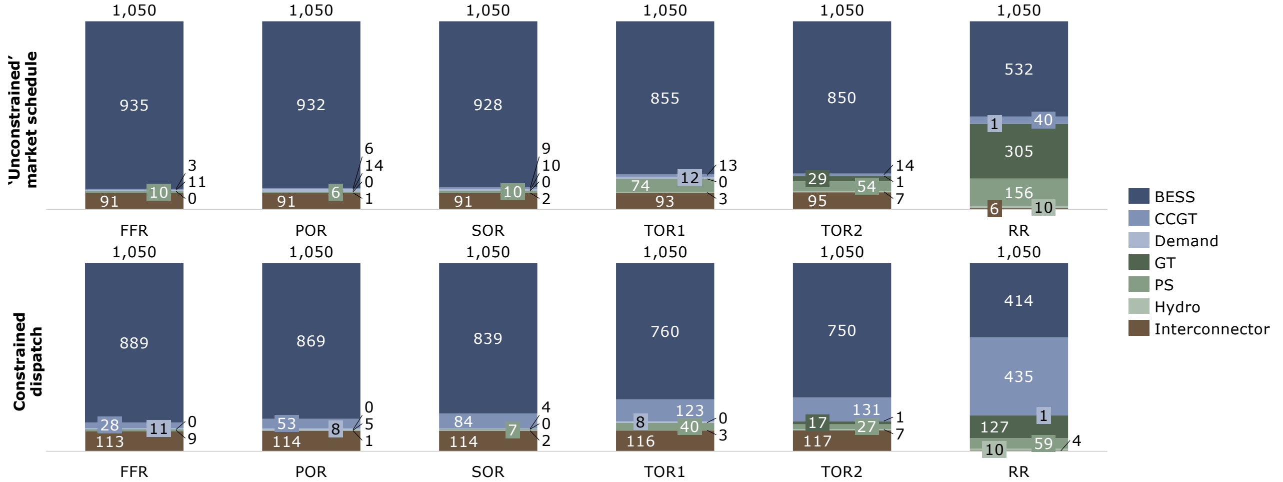
We need to again reiterate that across this entire analysis **we ignore any internal network congestion**, beyond the N-S tieline. Additional generation may have to be 'turned down' due to further network limitations (other than what is captured under the operational constraints as described in the previous chapter). In the same way that some energy output cannot be accommodated, some of the 'headroom' will be sterilised and alternative reserve volumes will need to be used. This additional change in generation and indirectly change in reserve provision is not captured in our analysis.

The reserve requirement we have used is static and equal to 1050MW for each reserve product. We also assume that wind and other non-synchronous renewables do not participate in the DASSA and are then also not used for reserve provision in real-time[5].

BESS is expected to dominate reserve provision in the DASSA. This is not surprising as it can be the most cost-effective source of reserve provision, especially in a world with a lot of renewable non-synchronous generation and the absence of constraints that require thermal units to be online. In a system with high levels of wind and relatively high levels of storage, there is little room for thermal generation given its relative short-run marginal cost. Energy demand is met by renewables and reserve predominantly by storage. It is only Replacement Reserve (RR) where there is increased scope for GTs and CCGTs for reserve provision. This is because of the energy limitations of BESS. The average hourly reserve provision in the 'unconstrained' market schedule (DASSA) and the constrained dispatch are presented in Exhibit 6.

[5] We believe that reserve provision from renewables should be encouraged and expect wind and other non-synchronous renewables to have an increasing role in reserve provision. In these model runs, we have excluded such provision for simplicity and to focus on changes across other technologies.

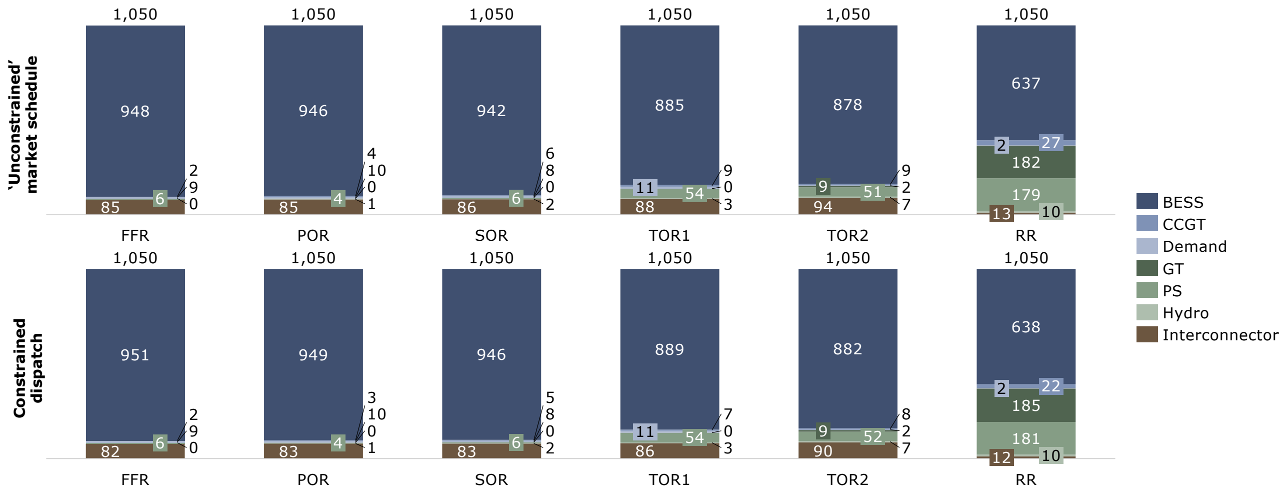
Exhibit 6 – Average hourly DASSA awarded contracts versus reserve provision in the presence of constraints (MW) – 2027



In practice, the All-Island system cannot be operated solely with non-synchronous generation – at least in the short to medium term. In addition, flows between Northern Ireland and Ireland are constrained. This is also reflected in the real-time reserve provision for RR. There is little change in the average provision of FFR, POR and SOR, as the contribution from thermal generation is much more limited. However, for slower response products (such as RR), there is greater scope for thermal units to provide part of the requirement.

We need to be careful how we read these results. This is the average provision by technology type – the delta between the unconstrained market schedule and constrained dispatch results presented **is not** equal to the change between the timeframes and the reserve volumes needed post Gate Closure, given that there may also be shifts within a technology type (and such an analysis should look at the deltas on an hourly basis). This is in any case meant to give a flavour of the changes that take place because of constraints.

Exhibit 7 – Average hourly DASSA awarded contracts versus reserve provision in the presence of constraints (MW) – 2030



3.2 How does reserve provision change closer to real-time?

We have modelled three different cases:

- **High compensation payment** (and highly liquid secondary trading) – in this case the compensation payment is so high that all DASSA Order holders would always attempt to transfer their obligation to an alternative provider in the secondary market. We then assume that this is sufficiently liquid and there are always alternative providers. The only possibility for alternative volumes needed outside this secondary trading route is in the case of post Gate Closure unavailability;
- **Mid compensation payment** – this case assumes the presence of a real-time market for reserve. DASSA Order holders that are moved away from the original position would only do so if the income from the real-time electricity price is greater than that implied from the real-time reserve price (equivalent to facing a compensation payment[6] of real-time reserve price minus DASSA price);
- **No compensation payment** – in this case a DASSA Order is effectively an option and we do not include explicit reserve requirements in the real-time dispatch. Units are scheduled to meet all other operation constraints and electricity demand and the reserve requirement is met only indirectly through headroom from the different units as they are dispatched to meet power demand and all other system constraints.

On the basis of an effective secondary market, we estimate that the need for alternative provision because of post Gate Closure unavailability is in the range of 6-33MW for each product on average. Assuming average unavailability for the different technologies and an average duration for any outage, this need for alterative provision is around 12MW for each product. This is a very small share (around 1%) of the overall requirement of 1050MW for each of the reserve products.

This is on the basis that post Gate Closure unavailability is the only potential reason for some of the reserve procured directly under DASSA or through secondary trading becoming unavailable, and should be viewed as the absolute minimum level, reflective of typical outage probabilities for the different technologies:

- CCGTs are typically on a forced outage for 12% of the time in a year;
  - however, when a CCGT 'trips', we assume that it is unavailable for the settlement period when this happens and the next one, and for all subsequent periods it can use the secondary market to trade its obligation with alternative supply;
- the assumed unavailability for BESS is 5% with a much shorter duration when there is a 'trip'.

[6] It is yet unclear what the compensation payment will be, but this modelling is considered reasonable for modelling a more 'dynamic' approach to the compensation payment

As already discussed, this case assumes high levels of liquidity in the secondary market and a compensation payment that is sufficiently high to encourage DASSA Order holders, including those that are moved because of non-energy TSO actions, to always find replacement volumes in the secondary market.

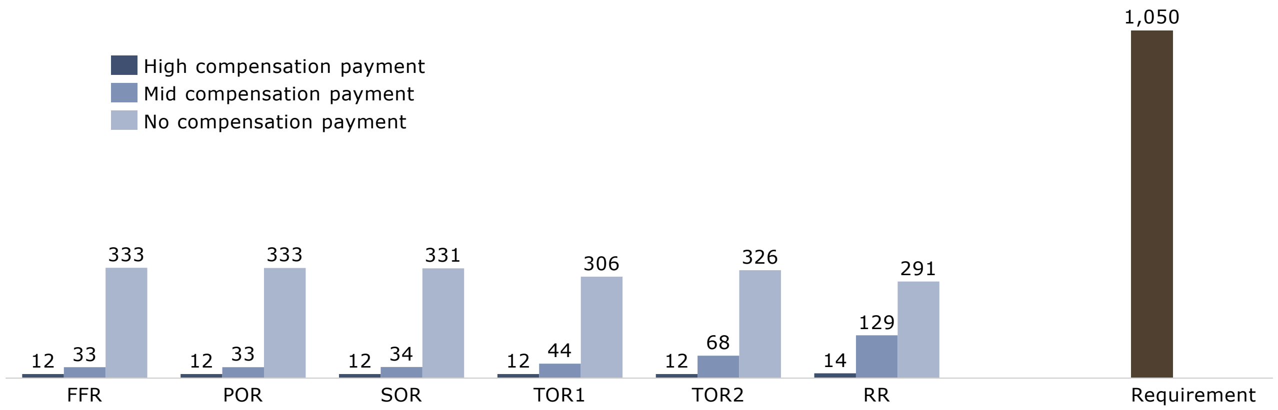
After the DASSA, system conditions change. Demand can increase or renewables output can be lower than expected. This also has an impact on electricity price formation. This, in turn, means that some DASSA Order holders may choose to lapse their DASSA Orders and opt for an energy payment. This behaviour can obviously only happen if the relative net payments justify this choice. In the 'Mid compensation payment' case, DASSA Order holders would move away from their original positions should this result in a more efficient solution from a system-wide perspective and improved margins for the provider.

This then results in a significant increase in the 'deficit' created from the ex-ante reserve markets (How much of the 1050MW originally contracted through the DASSA and not then replaced in secondary market needs to be procured in real-time?). On average, for the 'faster' reserve products (FFR-SOR) this is around 3% of the overall requirement, and more than 10% for RR.

In the absence of any compensation payment, we expect that almost 30% of all reserve volumes procured through the DASSA will not be available in real-time.

Exhibit 8 shows the average hourly change between DASSA volumes (or volumes that have assumed DASSA Orders in the secondary market) and real-time reserve provision.

Exhibit 8 – Average hourly change between DASSA volumes and real-time reserve provision (2027)



Note: Modelled year 2027

The 'High compensation payment' case and the 'No compensation payment' cases are the two extremes:

— on the one hand, there is the intention to have a compensation payment; and

- on the other hand, it will be challenging to set a compensation payment that is always at a level that encourages to trade in the secondary market and there may be instances when there is no sufficient depth in the secondary market.

The 'Mid compensation payment' represents a more probable scenario. Even in this case, the average hourly volumes that are no longer available in real-time appear to be small when compared to the overall requirement. This 'deficit', however, can be significant in individual periods.

3.2.1 Distribution of reserve 'deficit'

In the previous section we presented the reserve 'deficit'. We defined this 'deficit' as any difference between the volumes procured in the DASSA and the volumes that remained available in real-time. If, for example, the 1050MW POR requirement was met in the DASSA by 550MW from Provider A and 500MW from Provider B, there would be no 'deficit' if Provider A and Provider B continued to have 550MW and 500MW of POR available respectively in real-time. However, should Provider A have 500MW available for POR instead of 550MW, then this would be classed as a 50MW 'deficit' of POR in that given period. A 'deficit' therefore does not mean, there is not sufficient reserve to meet the requirement. It suggests a gap in reserve that needs to be met by alternative volumes (other than those procured in the DASSA or through secondary trading), and the TSOs would need to take balancing actions to ensure volume sufficiency

For almost 50% of the time, we do not see any 'deficit' in terms of FFR, POR, SOR and TOR1[7] in 2027. This is expected – most of the provision is coming from BESS that tends to be idle for a significant period of time. This is slightly lower for TOR2 (at around 40% of the time) and significantly lower for RR (only 10% of the time).

The 'deficit' is significant at peak times (when electricity prices are high) and times of high renewables output. For 15% of the time the TOR1 deficit is greater than 100MW and for more than 10% of the time the FFR, POR and SOR deficit is more than 100MW. For 1% of the time the TOR1 deficit is greater than 360MW and the FFR, POR and SOR deficit is greater than 275MW.

The 'deficit' we have estimated does not necessarily entail insufficient reserve in real-time. The TSOs can take dispatch instructions to ensure they have the reserve they need. However, this 'deficit' suggests a risk of having access to more limited reserve resources as the providers may find reserve provision a less attractive market.

[7] We need to note that as plant outages are modelled as an increase in demand, we do not capture their impact on the hourly results presented.

Exhibit 9 – Distribution of reserve 'deficit' (2027 with Mid compensation payment case)

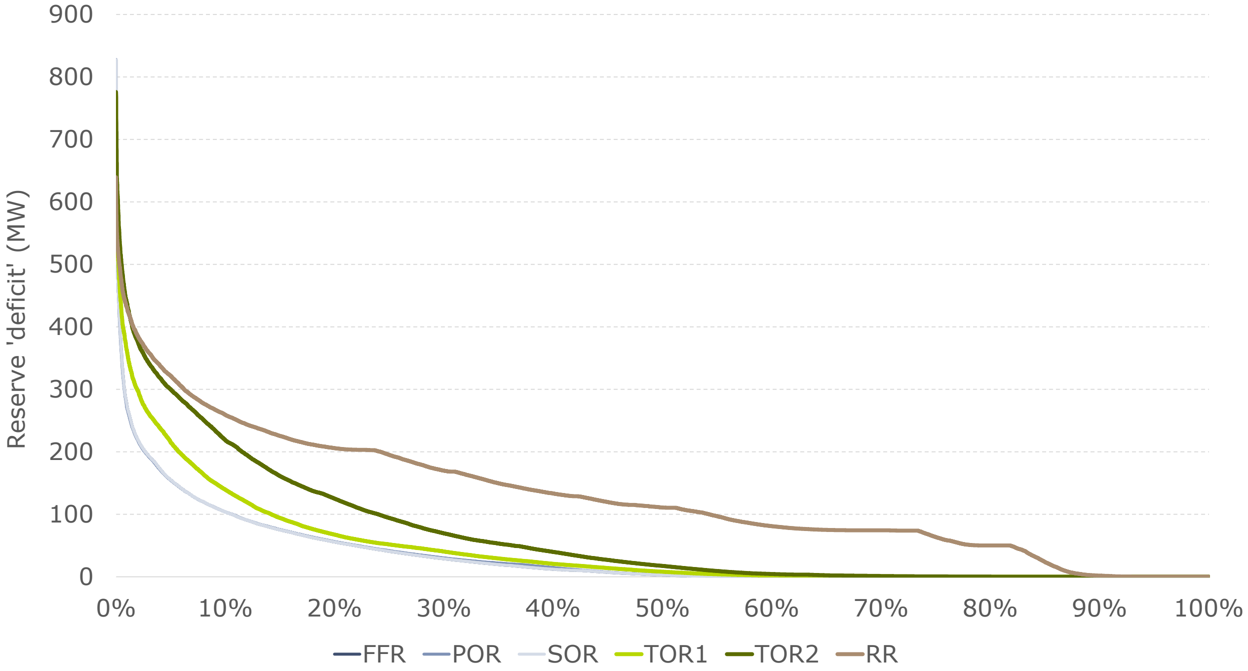
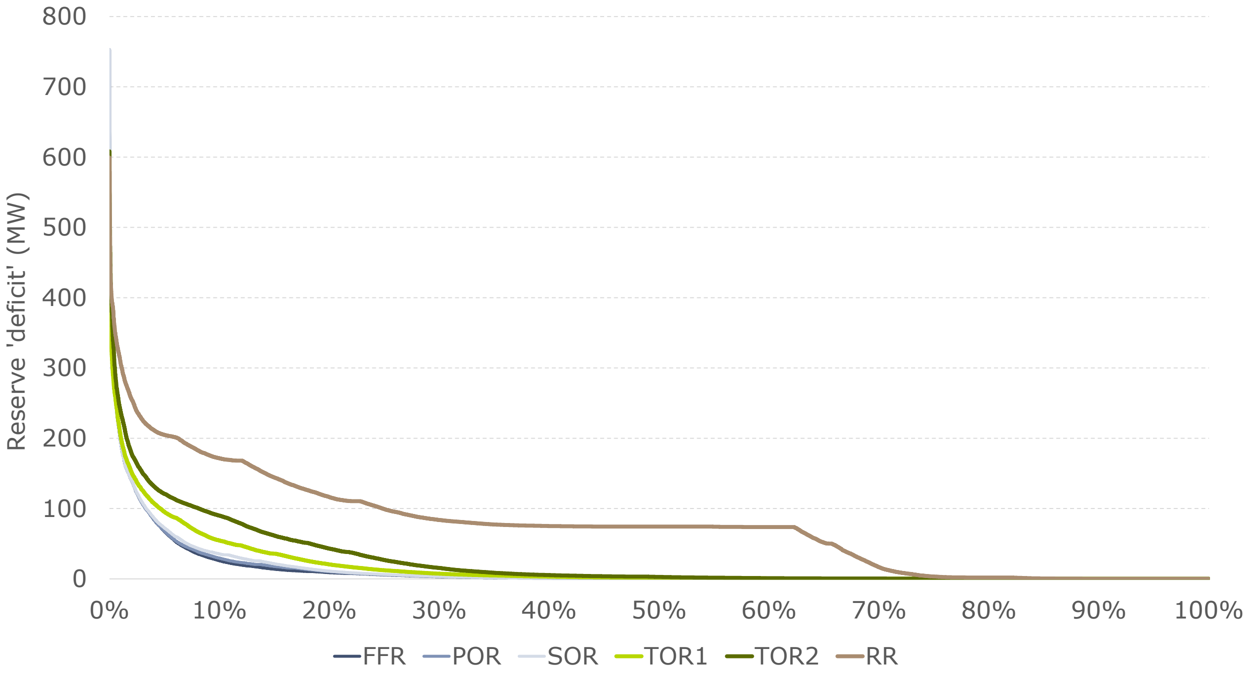


Exhibit 10 – Distribution of reserve 'deficit' (2030 with Mid compensation payment case)



3.2.2 Is there a risk of insufficient reserve in the case of no compensation?

In the real-time model run with no reserve constraints in place, more than 300MW of the DASSA procured volumes were no longer available in real-time. We have however, looked at the alternative headroom that was available to replace these volumes. This was limited – there is no incentive for units to 'part-load' and keep headroom. This is because the Balancing Market is not set up to incentivise reserve provision, rather provision of energy. For example, a BESS that is not injecting to the grid, and can provide reserve, would not receive any payment from the Balancing Market, unless it is activated because of a frequency event.

For a very large share of the periods in a year there was actually insufficient headroom to meet the reserve requirement, as shown in Exhibit 11.

Exhibit 11 – Percentage of hours with insufficient 'headroom' to meet the reserve requirement in the absence of appropriate compensation

	2027	2030
FFR	29%	28%
POR	32%	33%
SOR	31%	35%
TOR1	23%	27%
TOR2	22%	27%
RR	0%	7%

Over these periods the average 'deficit' in MW is presented in Exhibit 12.

Exhibit 12 – Average MW 'deficit' in periods with insufficient headroom to meet the requirement in the absence of appropriate compensation

	2027	2030
FFR	375	402
POR	379	400
SOR	360	396
TOR1	273	361
TOR2	279	371
RR	83	145

The TSOs would not permit this to happen in operational timeframes. They would use the Balancing Market to issue instructions to the different units to create the required headroom. This then means using bids and offers from the Balancing Market to reposition units. This is not uncommon practice for most TSOs – the Balancing Market is often used not only to manage the supply and demand balance, but to deal with wider system operation. However, this then raises issues with price formation and the potential 'pollution' of the imbalance price. From a provider perspective, units are compensated for the energy injected to the system, but not for the reserve provided.

In the absence of any explicit compensation, we can assume that providers may even default to the Grid Code minimum contribution of 5% towards the reserve products. In such a case, the TSOs may find it challenging to find the additional volumes needed to cover for this ‘deficit’.

Exhibit 13 shows the percentage of hours when there is insufficient reserve supply to meet the requirement, assuming that the contribution from units that were not awarded a DASSA contract is capped at 5% of their nameplate capacity. Any ‘deficit’ created assuming the ‘Mid compensation payment’ case can now be managed by a more limited supply of reserve. At this point, it is important to remind ourselves the distribution of the ‘deficit’ presented in Exhibit 9. For a small number of periods in a year there is a clear risk of insufficient reserve volumes.

Exhibit 13 – Percentage of hours with insufficient ‘headroom’ to meet the reserve requirement assuming minimum provision from all units

	2027	2030
FFR	1.0%	0.6%
POR	0.7%	0.7%
SOR	0.7%	0.6%
TOR1	1.8%	0.5%
TOR2	4.2%	0.8%
RR	24.1%	7.7%

Over those the periods the average ‘deficit’ in MW is presented in Exhibit 14.

Exhibit 14 – Average MW ‘deficit’ in periods with insufficient headroom to meet the requirement assuming minimum provision from all units

	2027	2030
FFR	124	139
POR	128	137
SOR	128	138
TOR1	104	102
TOR2	106	123
RR	141	101

4 Conclusions

Storage is expected to be an important reserve provider, but there is scope for thermal generating units in the short-term given the presence of operational constraints

Storage is more competitive in the DASSA and is in a position to meet most of the reserve requirements[8]. CCGTs and other thermal units are needed infrequently on an unconstrained basis and this makes their reserve less attractive. At an annual level, we expect CCGTs and GTs to be much less competitive in the DASSA for the provision of reserve. The only exception is RR – given the energy limitation of storage there is still scope for thermal units to provide RR.

This changes in actual dispatch, given the presence of constraints. CCGTs then have ‘headroom’, which is equally (if not more) cost-effective as (than) storage awarded contracts through the DASSA. This does not mean that the TSOs no longer have access to the already awarded DASSA contracts – we simply highlight the difference in the efficient solution between an ‘unconstrained’ and a ‘constrained’ system.

We need to provide long-term signals for innovative reserve provision, and, at the same, time retain renumeration for thermal providers in this transitional phase

This does raise the question as to whether it would have been preferrable to hold the DASSA auctions post LTS, and once the TSOs have issued dispatch instructions. If this was the case, CCGTs that receive dispatch instructions through the LTS would become competitive and be in a position to be awarded DASSA contracts, displacing storage units. This may appear to result in a lower cost to consumers, but this would only be in the short-term. The incentives for innovative provision of reserve would be dampened, and the All-Island system may then continue to be reliant on CCGTs for meeting the system-wide reserve needs. Fuel use and carbon emissions would not drop, and we would not see an improvement in the variable operating system costs. The benefits from innovative provision of system services have been discussed extensively, and are very significant.

We, therefore, consider it is important to:

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[8] This does, however, assume there is no minimum requirement for ‘spinning’ reserve. We expect the TSOs will continue to need a minimum level of ‘spinning’ reserve.

- have an ‘unconstrained’ market signal in the DASSA to incentivise innovative provision that can help the TSOs in their process to relax operational constraints; and
- retain an incentive for some thermal providers that can provide reserve whilst constraints persist.

The need for alternative reserve volumes can be as low as 1% of the requirement assuming adequate liquidity in the secondary market and a compensation payment that encourages efficient trading at all times

The need for any further procurement of and/or remuneration for reserve is very limited assuming:

- a sufficiently liquid secondary market; and
- a compensation payment set always at a level that encourages effective secondary trading of reserve.

The former is not guaranteed and the latter is impossible to happen at all times, unless the compensation payment is set at a high level across all periods. We would advise against this as this would unnecessarily increase risk for providers and would result in significantly higher cost for consumers.

Still, on the basis of these very ambitious assumptions, there would on average be a need for only around 1% of the reserve volumes to come from alternative sources. This would only happen because of plant outages post Gate Closure, when secondary trading is no longer available.

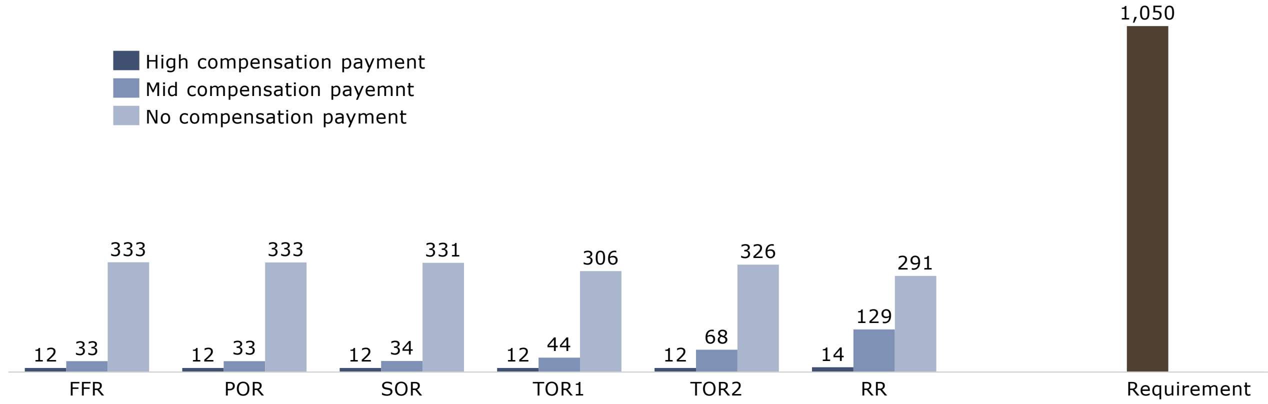
On the other hand, the TSOs may be forced to have to replace, on average, 30% of the reserve volumes if the commitment obligations are ‘weak’

We have modelled a case, where providers can treat DASSA Orders as an option. As conditions on the system change, a significant share of the reserve volumes move from the original position responding to electricity price signals. In the absence of a real-time signal for reserve and/or ‘weak’ obligations under the DASSA Orders, there is little incentive for units to make headroom available for reserve.

In reality, the need for alternative reserve will be somewhere inbetween the two extremes

The average hourly change between reserve volumes from the market and what is then available in real-time ranges from 3% for FFR to 10% for RR assuming a more cost-reflective compensation payment

Exhibit 15 – Average hourly change between DASSA volumes and real-time reserve provision (2027)

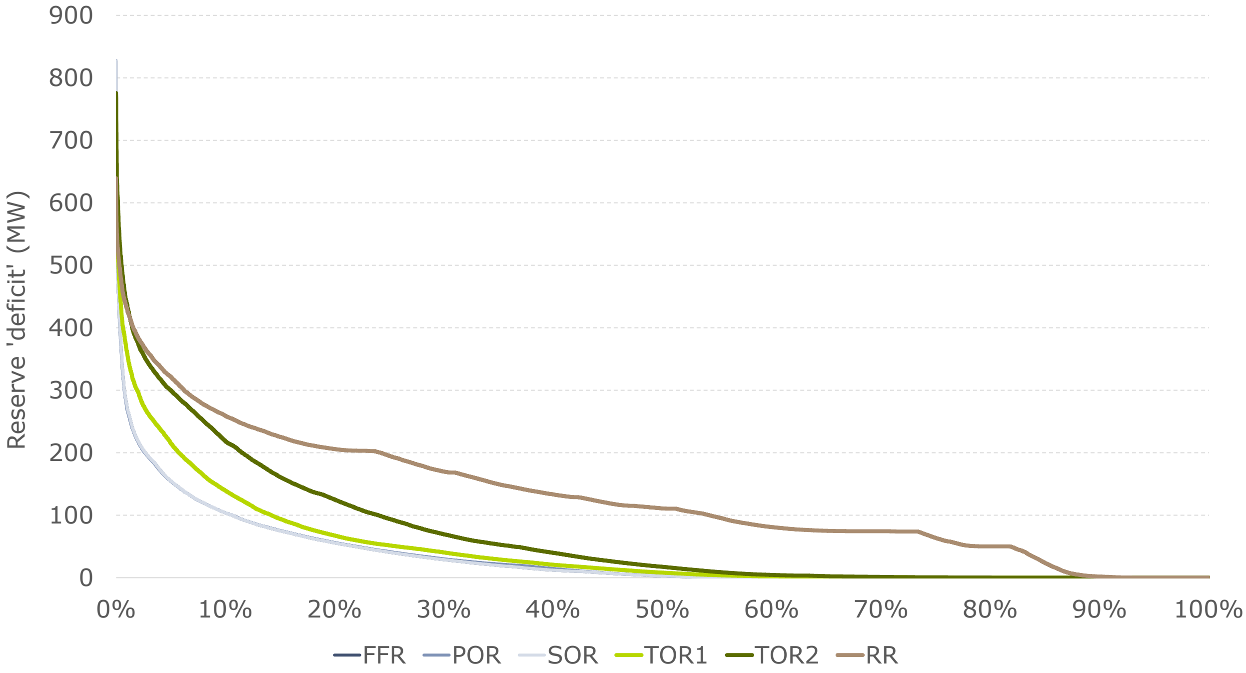


Note: Modelled year 2027

This still does not sound much as an annual average value … but in some periods the potential need for alternative volumes is very high

For 10% of the periods of the year (ie more than 3 hours per day on average) the real-time reserve 'deficit' is more than 100MW for each reserve product.

Exhibit 16 – Distribution of reserve 'deficit' (2027 with Mid compensation payment case)



Without clear pricing signals, providers may choose to solely offer the minimum envisaged under the Grid Code, and this can risk system security

We have also found that, if we were to assume that providers (that do not hold a DASSA Order) offer only 5% of their nameplate capacity for reserve provision, there will be periods where the TSOs may be unable to find enough reserve to cover for this market 'deficit' This means the All-Island system does not have enough reserve in these circumstances (assuming that even if there is enough headroom, the TSOs can only rely to a capped 5%).

Units that are positioned or used in actual dispatch for reserve should capture a relative payment in line with the service they provide to the system. It is necessary to provide an incentive that ensures this is sustained over time. There is, otherwise, a risk that some units have little incentive to provide reserve beyond the grid code minimum. Relying solely on the Grid Code minimum can risk system security.

We support explicit pricing of reserve and any effort that brings us closer to a real-time reserve market/price

A real-time market and/or mechanism can be used to procure and remunerate additional and/or replacement reserve volumes, in the same way the Balancing Market is used to ultimately balance supply and demand. There is an argument that this is not needed and any relevant compensation can be through energy payments in the Balancing Market and/or through non-energy actions prior to Gate Closure. There is an issue with this approach. Any payments through the Balancing Energy would be in effect indirect – the units would be paid for their energy output and not for the reserve they are providing.

This last point is important. It is true that there are very few examples where a real-time price for reserve exists. However, the importance of reserve is increasing with more non-synchronous generation added to the system, and an explicit price signal for reserve appears to be the way forward. If this is not the case, there will be less transparency for providers as they will not be in a position to understand what the system values most – their energy or their reserve?

Annex A Key modelling assumptions

A.1 Demand assumptions

Exhibit 17 – Annual All-Island demand (TWh)

2027	2030
51.0	57.9

A.2 Commodities assumptions

Exhibit 18 – Gas price projections at the NBP hub (p/therm, real 2023 money) and EUA CO_2 price projections (EUR/tCO_2, real 2023 money)

	2027	2030
NBP Gas (p/therm)	75.6	65.7
EUA CO_2 (EUR/tCO_2)	115.2	139.6

A.3 Installed capacity assumptions

Exhibit 19 – All-Island installed capacity (GW)

	2027	2030
Battery	1.3	1.7
Biomass	0.1	0.1
CCGT	4.4	4.7
CHP	0.3	0.3
Demand Shedding	0.9	0.9
Engine	0.4	0.4
GT	2.9	3.9
Hydro	0.2	0.2
Offshore Wind	0.0	1.1
Onshore Wind	7.4	8.7
Other Renewables	0.0	0.0
Pumped Storage	0.3	0.3
Solar PV	4.8	6.5
Waste	0.1	0.1
Interconnection	2.2	2.2

TABLE OF EXHIBITS

Document control

Report Identifier: 2025

Version	Date	Comments
v100	14-Mar-2025	Initial client release.
v500	15-Jul-2025	Final release

AFRY

We don’t care much about making history.

We care about making future.

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